ORIGINAL

E000010422

Court S. Rich - AZ Bar No. 021290
Eric A. Hill - AZ Bar No. 029890
Rose Law Group pc
7144 E. Stetson Drive, Suite 300
Scottsdale. Arizona 85251
Bus: (480) 505-3937
crich@roselawgroup.com
ehill@roselawgroup.com
Attorneys for the Solar Energy Industries Association

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB BURNS CHAIRMAN	BOYD DUNN COMMISSIONER	SANDRA KENNEDY COMMISSIONER
JUSTIN OLSON COMMISSIONER	LEA MÁRQUEZ PETERSON COMMISSIONER	

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	**DOCKET NO. E-01345A-19-0236** **SOLAR ENERGY INDUSTRIES ASSOCIATION'S SURREBUTTAL TESTIMONY OF KEVIN LUCAS**

Solar Energy Industries Association ("SEIA") hereby provides notice of filing the Surrebuttal Testimony of Kevin Lucas in the above referenced matter.

RESPECTFULLY SUBMITTED this 4th day of December, 2020.

ROSE LAW GROUP pc

/s/ Court S. Rich
Court S. Rich
Eric A. Hill
Attorneys for Solar Energy Industries Association

ACC - Docket Control - Received 12/4/2020 3:15 PM
ACC - Docket Control - Docketed 12/4/2020 3:26 PM

Original e-filed and 8 copies hand delivered on this 4th day of December, 2020 with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

I hereby certify that I have this day served a copy of the foregoing document on all parties of record in this proceeding by regular or electronic mail to:

Robin Mitchell
Arizona Corporation Commission
legaldiv@azcc.gov
utildivservicebyemail@azcc.gov

Melissa Krueger
Pinnacle West Capitol Corporation
melissa.krueger@pinnaclewest.com
thomas.mumaw@pinnaclewest.com
theresa.dwyer@pinnaclewest.com
rodney.ross@aps.com
andrew.schroeder@aps.com
leland.snook@aps.com
ratecase@aps.com

Adam Stafford
Western Resource Advocates
stacy@westernresources.org
adam.stafford@westernresources.org
steve.michel@westernresources.org
autumn.johnson@westernresources.org

Timothy Hogan
ACLPI
thogan@aclpi.org
ezuckerman@swenergy.org
briana@votesolar.org
Sandy.bahr@sierraclub.org
louisa.eberle@sierraclub.org
janderson@aclpi.org
sbatten@aclpi.org
czwick@wildfireaz.org
cpotter@swenergy.org
miriam.raffel-smith@sierraclub.org
rose.monahan@sierraclub.org
brendon@gabelassociates.com

Greg Patterson
Munger Chadwick/Competitive Power Alliance
greg@azcpa.org

Richard Gayer
rgayer@cox.net

Patrick Black
Fennemore Craig, PC
pblack@fclaw.com
lferrigni@fclaw.com

Daniel Pozefsky
RUCO
dpozefsky@azruco.gov
procedural@azruco.gov
jfuentes@azruco.gov
rdelafuente@azruco.gov

Robert Miller
bob.miller@porascw.org
rdjscw@gmail.com

Kurt Boehm
Boehm, Kurtz & Lowry
kboehm@bkllawfirm.com
jkylercohn@bkllawfirm.com

Jason Moyes
Moyes Sellers & Hendricks
jasonmoyes@law-msh.com
jim@harcuvar.com
jjw@krsaline.com

Nicholas Enoch
Lubin & Enoch, PC
nick@lubinandenoch.com
bruce@lubinandenoch.com
clara@lubinandenoch.com

Patricia Madison
Patricia_57@q.com

Jonathan Jones
jones.2792@gmail.com

Karen White
Scott Kirk
Robert Friedman
Thomas Jernigan
Holly Buchanan
karen.white.13@us.af.mil
scott.kirk.2@us.af.mil
robert.friedman.5@us.af.mil
thomas.jernigan.3@us.af.mil
ebony.payton.ctr@us.af.mil
arnold.braxton@us.af.mil
holly.buchanan.1@us.af.mil

John Thornton
john@thorntonfinancial.org

Scott Wakefield
Hienton Curry, P.L.L.C.
swakefield@hclawgroup.com
stephen.chriss@walmart.com

Kimberly Dutcher
Navajo Nation Dept. of Justice
kdutcher@nndoj.org
aquinn@nndoj.org

Jason Mullis
Wood Smith Benning & Berman LLP
jmullis@wshblaw.com

Gregory Adams
greg.bass@calpinesolutions.com
greg@richardsonadams.com

Albert Acken
Dickinson Wright PLLC
aacken@dickinson-wright.com

Giancarlo Estrada
Kamper Estrada, LLP
gestrada@lawphx.com

Garry Hays
Law office of Garry Hays PC
ghays@lawgdh.com

Armando Nava
The Nava Law Firm PLLC
filings@navalawaz.com

John Coffman
John B. Coffman
John B. Coffman LLC
john@johncoffman.net

Thomas Harris
Distributed Energy Resource Association
thomas.harris@dera-az.org

Marta Darby
David Bender
Earthjustice
mdarby@earthjustice.org
dbender@earthjustice.org

Shelly Kaner
8831 W. Athens Street
Peoria, Arizona 85382

By: /s/ Hopi L. Slaughter

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	)))))))))))	**DOCKET NO. E-01345A-19-0236** **SEIA'S NOTICE OF SURREBUTTAL TESTIMONY OF KEVIN LUCAS**

SURREBUTTAL TESTIMONY

OF

KEVIN LUCAS

ON BEHALF OF

Solar Energy Industries Association ("SEIA")

DECEMBER 4, 2020

Table of Contents

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A1. My name is Kevin Lucas. I am the Director of Rate Design at the Solar Energy Industries Association (SEIA). My business address is 1425 K St. NW #1000, Washington, DC 20005.

Q2. ARE YOU THE SAME KEVIN LUCAS THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A2. Yes.

Q3. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A3. My testimony is provided on behalf of Intervenors, SEIA and the Arizona Solar Energy Industry Association (AriSEIA).

Q4. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A4. My testimony rebuts testimony from Staff witness David E. Dismukes on rate design and provides surrebuttal testimony to several Arizona Public Service ("APS" or "the Company") witnesses on matters of rate design and cost of service.

Q5. PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.

A5. I disagree with several elements of Staff witness Dr. Dismukes's testimony on rate design. Specifically, his suggestion to change the measurement of residential demand rates from on-peak hours to all hours (i.e. non-coincident peak demand) is highly problematic and should be rejected. His recommendations to discontinue all seasonal demand rates and time-differentiated volumetric rates on the R-2 and R-3 tariff is not sound. Finally, Dr. Dismukes's call to remove the super-off peak period is not consistent with energy costs or state policy to increasingly integrate renewable energy.

I also disagree with the position of several APS witnesses. The Company's rebuttal testimony from Mr. Brad Albert and Ms. Jessica Hobbick on changing residential time-of-use ("TOU") hours failed to directly address much less refute the many substantive arguments that were raised in SEIA's direct testimony. Mr. Jacob Tetlow appears to misunderstand the relationship between the DC nameplate capacity and AC inverter capacity in a PV system, and consequently offers incorrect testimony related to the appropriate method to size systems. Ms. Hobbick's rebuttal of SEIA's recommendations related to the R-TECH rate design modifications and expansion of the R-2 and R-3 demand limiter to all customers fall short. Finally, Mr. Leland Snook repeats the same unconvincing arguments on cost of service issues as he has for several years and misconstrued both the history of the E-32 Storage Pilot design and SEIA's recommended changes to that tariff.

Q6. DOES YOUR FAILURE TO REBUT OTHER PARTIES' TESTIMONY OR OTHER PARTS OF STAFF'S AND APS'S TESTIMONY IMPLY ANY AGREEMENT ON THOSE POSITIONS?

A6. No, it does not.

Q7. DID YOU REVIEW THE COMPANY'S ADVANCED ENERGY MECHANISM ("AEM") PROPOSAL?

A7. Yes, I did. The AEM proposal is a reasonable approach that will assist the Company as it makes the transition to a clean energy future.

II. SURREBUTTAL TO STAFF WITNESS DAVID E. DISMUKES REGARDING RATE DESIGN

Q8. WHAT IS DR. DISMUKES'S RECOMMENDATION ON HOW DEMAND SHOULD BE MEASURED FOR RESIDENTIAL CUSTOMERS ON THE R-2 AND R-3 TARIFF?

A8. Dr. Dismukes recommends that the measurement of demand shift from the highest measured demand during on-peak hours (currently 3 PM to 8 PM weekdays) to the highest measured demand during any hour of the month.[1] The latter value is also called the customer's non-coincident peak ("NCP") demand.

Q9. HOW DOES DR. DISMUKES JUSTIFY THIS CHANGE?

A9. He suggests that since most utilities with residential demand charges utilize NCP demand charges[2] and claims that since APS appeared to open the door to NCP demand charges when residential customers "become accustomed to three-part rates", that it is now an appropriate

[1] Dismukes Direct at 45.
[2] Dismukes Direct at 44.

time to adopt NCP demand charges to "provide additional ease of understanding and simplify billing requirements."[3]

Q10. IS DR. DISMUKES'S FIRST POINT RELATED TO THE PREVALENCE OF NCP DEMAND CHARGES RELEVANT?

A10. No. Measuring NCP demand charges require only basic metering capabilities – a meter capable of recording the maximum demand in a given month – while measuring peak period demand requires more sophisticated metering such as APS's AMI meters. Utilities that implement NCP demand charges may be doing so simply due to a metering limitation and not due to a proactive policy choice. Regardless of this, that other utilities choose to implement NCP demand charges for residential customers does not justify the policy, as I will discuss momentarily.

Q11. IS DR. DISMUKES'S CLAIM THAT APS STATED "THE USE OF NCP DEMAND MEASUREMENT IS NOT SUITED FOR ITS RESIDENTIAL CUSTOMERS, AT LEAST UNTIL THEY BECOME ACCUSTOMED TO THREE-PART RATES" ACCURATE?

A11. No, it is not. Dr. Dismukes was referencing APS's Long-Range Rate Plan as support for this statement, but he misrepresents that document.[4] The actual passage from the document follows:

> Although there are theoretical arguments that would support measuring demand over shorter time intervals and also distinguishing non-coincident demand from coincident demand, these refinements to the traditional three-part rate are probably not well-suited for residential customers. Thus, APS plans to continue its historical practice with demand rates of using a one-hour time period for measuring demand (more lenient in contrast to the 15 minute period used for business customers) and measuring the demand only in the on-peak time period. This would provide a significant number of hours, including weekends, that are off-peak and would not create a billing demand. Also, as a transition mechanism, APS plans on proposing an extra-small residential customer rate and a minimum load factor provision for very low load factor customers. As customers become increasingly accustomed to three-part rates, more sophisticated rate structures could be created to further maximize a customer's control over their bill.[5]

[3] Dismukes Direct at 45.
[4] Dismukes Direct at 44.
[5] ACC Docket No. E-01345A-16-0036; APS witness Snook, Dir. Test., Attachment LRS-05DR, at pp. 14-15. (June 1, 2016).

Nowhere in this passage does APS state that NCP demand charges meet the definition of "more sophisticated rate structures" as Dr. Dismukes implies. In fact, APS is quite clear that either shortening the interval from one hour to 15 minutes and moving from on-peak to NCP demand "are probably not well-suited for residential customers." The final sentence can most reasonably be read to modify the proposed "transition mechanism" offering the extra-small rate (realized in the R-XS flat tariff) and minimum load factor provision (realized through the demand ratchet limiter), suggesting it may be appropriate to revisit these provisions as customers become more accustom to three-part rates.

Q12. NOTWITHSTANDING THE POTENTIAL AMBIGUITY IN THE LONG-TERM RATE PLAN THAT STEMMED FROM A 2012 COMMISSION ORDER,[6] DID APS AGREE WITH DR. DISMUKES'S RECOMMENDATION ON THIS POINT?

A12. No, it did not. APS Witness Hobbick criticized this recommendation, correctly indicating that it "undermines conservation" and "is also overly punitive to customers because it requires them to manage their usage around the clock."[7] I agree with Ms. Hobbick on these points.

Q13. ASIDE FROM THE TWO ISSUES THAT MS. HOBBICK IDENTIFIED, ARE THERE OTHER REASONS WHY NCP DEMAND SHOULD NOT BE USED FOR BILLING PURPOSES?

A13. Yes. In the Company's class cost of service study ("CCOSS"), most demand-related costs are allocated based on demand measurements that appropriately reflect load diversity. Production and transmission assets are allocated based on measures of class coincident peak demand. Shared distribution assets such as substations are allocated based on class non-coincident peaks (which still account for the load diversity of individual customers). Only a small portion of the distribution system – the secondary voltage system close to the end customer – is allocated based on a sum of the individual NCP loads of customers. As such, billing an individual customer based on their individual NCP for all of their production, transmission, and

[6] Order 73183, Docket No. E-01345A-14-0224, May 24, 2012.
[7] Hobbick Rebuttal at 31-32.

distribution capacity costs that are recovered through demand charges is simply not reflective of cost-causation.

Additionally, NCP demand charges provide perverse incentives. Suppose a customer works from 12 PM to 8 PM, gets home, and turns on the air conditioning, makes dinner, and does laundry. This usage pattern results in their peaks occurring between 8 PM and 9 PM, outside of the peak period that drives capacity costs. If they were billed based on their peak demand during this time, they may decide to reduce this demand by programming their air conditioning to start at 7 PM and turn it off when the get home since they cannot make dinner or do laundry before returning. This will drive up the customer's demand during peak hours, which puts more stress on (and eventually adds costs to) the overall system, even as it reduces the individual customer's bill.

Q14. WHAT IS DR. DISMUKES'S RECOMMENDATION REGARDING THE SEASONALITY OF DEMAND RATES AND TOU VOLUMETRIC RATES ON THE R-2 AND R-3 TARIFFS?

A14. He recommends discontinuing all seasonal demand charges and dropping the TOU element of volumetric energy rates because "APS's residential rates are too complex and need to be simplified."[8]

Q15. DO YOU AGREE WITH THESE RECOMMENDATIONS?

A15. No, I do not. The demand charges in the R-2 and R-3 tariffs are seasonal to reflect the fact that power supply costs (i.e. production and transmission assets) are driven by summer peak demand. It is appropriate and consistent with cost-causation to recognize this in seasonally-differentiated rates. If the demand rate for power supply were constant year-round, it would send inappropriate signals that reducing usage during peak hours in the core summer months is worth no more than reducing usage during spring afternoons. Further, the TOU energy rates are reflective of the differential in the cost of producing energy during peak and off-peak hours.

[8] Dismukes Direct at 43.

Q16. WHAT IS DR. DISMUKES'S RECOMMENDATION WITH REGARD TO THE SUPER OFF-PEAK PERIOD?

A16. His recommendation is ambiguous. It appears he recommends the Commission reject the proposed addition of the super off-peak period to the R-2 and R-3 and remove it from the R-TOU-E, but his testimony states:

> Q. Should APS continue to offer its super off-peak winter rate within its standard TOU plan?
>
> A. No. I recommend that APS discontinue this rate altogether in order to increase the simplicity of its three-part tariff. APS's current demand rates are already overly complex and will likely benefit from a more simplified rate structure.[9]

It is unclear whether he recommends discontinuing the entire R-TOU-E tariff, or just the super off-peak rate portion of the tariff. Further, the R-TOU-E rate is not a three-part rate, and the current three-part rates (R-2 and R-3) do not have a super off-peak period. Whatever his intent, I do not agree with the recommendation to cancel the R-TOU-E tariff, to cancel the super off-peak period within the R-TOU-E tariff, or to disapprove of the addition of a super off-peak period to the R-2 and R-3 tariffs.

Q17. WHY IS THAT?

A17. The lower super off-peak period rate is reflective of lower cost energy and limited capacity needs during midday hours. It sends an appropriate price signal for customers to shift usage from later afternoon hours to midday hours when possible. This incentive aligns the interests of the individual (by lowering their bill) and the overall system (by reducing capacity needs and forgoing more expensive energy purchases), ensuring that even customers that do not shift their energy benefit from a long-term reduction in total system costs. While I understand Dr. Dismukes's desire to simplify APS's rates, I do not believe this recommendation is beneficial on balance.

---

[9] Dismukes Direct at 46.

Q18. WHAT DO YOU RECOMMEND WITH REGARD DR. DISMUKES'S RECOMMENDATIONS TO MOVE TO NCP DEMAND FOR RESIDENTIAL CUSTOMERS, TO ELIMINATE SEASONAL DEMAND RATES, ELIMINATE TOU VOLUMETRIC RATES ON THE R-2 AND R-3 TARIFF, AND TO ELIMINATE THE SUPER OFF-PEAK PERIOD?

A18. I recommend they all be disregarded. All are is inconsistent with cost-causation principles, and any benefits gained from simplification are lost through poor price signaling.

III. <u>SURREBUTTAL TO APS WITNESSES ALBERT, TETLOW, HOBBICK, AND SNOOK REGARDING RATE DESIGN AND COST OF SERVICE</u>

Q19. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU DISCUSS IN THIS SECTION.

A19. I provide surrebuttal testimony on seven topics that were addressed by four APS witnesses: the appropriate TOU seasons and hours (Mr. Albert and Ms. Hobbick), the alternative R-TECH proposal (Ms. Hobbick), the appropriateness of the Grid Access Charge ("GAC") (Ms. Hobbick), extending the demand limiter to solar customers (Ms. Hobbick), qualifying systems based on inverter size (Mr. Tetlow), cost of service issues (Mr. Snook), and commercial rate design issues, including the E-32 Storage Pilot program (Mr. Snook).

Q20. HAVE SEIA AND ARISEIA ALTERED ANY OF THE RECOMMENDATIONS THEY MADE IN YOUR DIRECT TESTIMONY?

A20. Yes. SEIA and AriSEIA are no longer asking the Commission to freeze the RCP rate at its current level in this proceeding. As a result, while I do not agree with APS witnesses' rebuttal testimony on this matter, I will not provide surrebuttal testimony on this topic.

SEIA's TOU Seasons and Hours are Appropriate and Well-Supported

Q21. WHAT RECOMMENDATIONS DID YOU MAKE REGARDING TOU SEASONS AND HOURS?

A21. I recommended that the summer season be changed to June through September, and that the peak hours be changed to 2 PM to 7 PM weekdays.[10] I based my analysis on the monthly

[10] Lucas Direct, Section III.

average system and residential class loads as well as an analysis of the top 500 load hours between 2016 and 2019.

Q22. DID APS DIRECTLY REBUT YOUR ANALYSIS RELATED TO THE TOU SEASONS AND PERIODS?

A22. No, it did not. While Mr. Albert and Ms. Hobbick addressed the TOU season and period analyses from other witnesses, they did not directly rebut my analyses on this point. Mr. Albert disagreed with Staff witness Dr. Dismukes and SWEEP and WRA witness Brandon Baatz's recommendation to shorten the TOU window to 4 PM to 7 PM and the analyses that supported that recommendation, specifically noting they used annual load shapes, used a sub-set of APS customers, and used only customer load, not system load.

Q23. DID YOUR ANALYSES SHARE THESE CHARACTERISTICS?

A23. No, they did not. I used monthly load shapes for both system load and residential class load and included all residential customers in the class load profiles. As such, Mr. Albert's critiques on these points are not relevant to my testimony.

Q24. WHAT REASONS DID MS. HOBBICK PROVIDE AGAINST YOUR RECOMMENDATION TO SHORTEN THE SUMMER SEASON TO FOUR MONTHS?

A24. Ms. Hobbick agreed that "generation capacity is typically planned to meet the system load in the four core summer months."[11] However, she said that the shoulder months "typically require[d] significant air-conditioning as temperatures often reach 100 degrees or more" and that while lower than the core summer months, the shoulder months' "daily load shape patterns more closely resemble the core summer months than the non-summer months."[12] Based on these factors and a desire to simplify residential rates and bills, Ms. Hobbick does not support changing to a four-month summer season.

Q25. WHAT IS YOUR RESPONSE TO THESE POINTS?

A25. I do not find these arguments persuasive. I performed a detailed analysis of the system and residential class loads and found a clear difference between the four core summer months and

[11] Hobbick Rebuttal at 16.
[12] Hobbick Rebuttal at 16.

the remaining eight months. Figures 1 and 2 below are taken from my direct testimony, showing the average load profile over four years.[13] May and October have average system loads that are roughly 2,000 MW lower than the core summer peak.

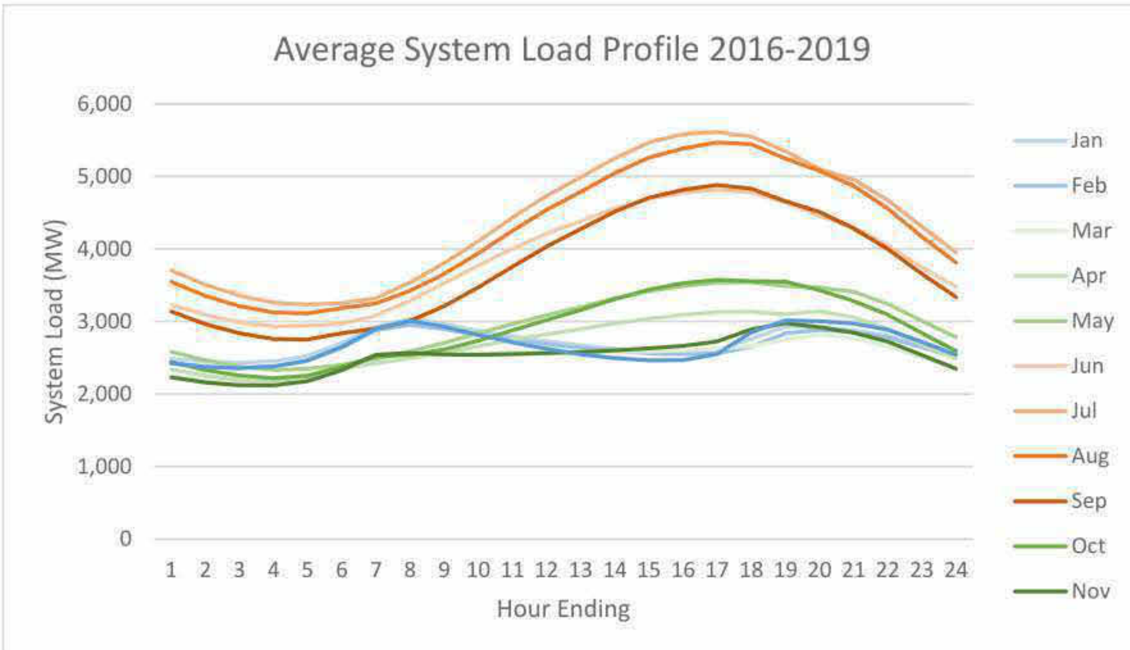

Figure 1 - Average System Load Profile 2016-2019

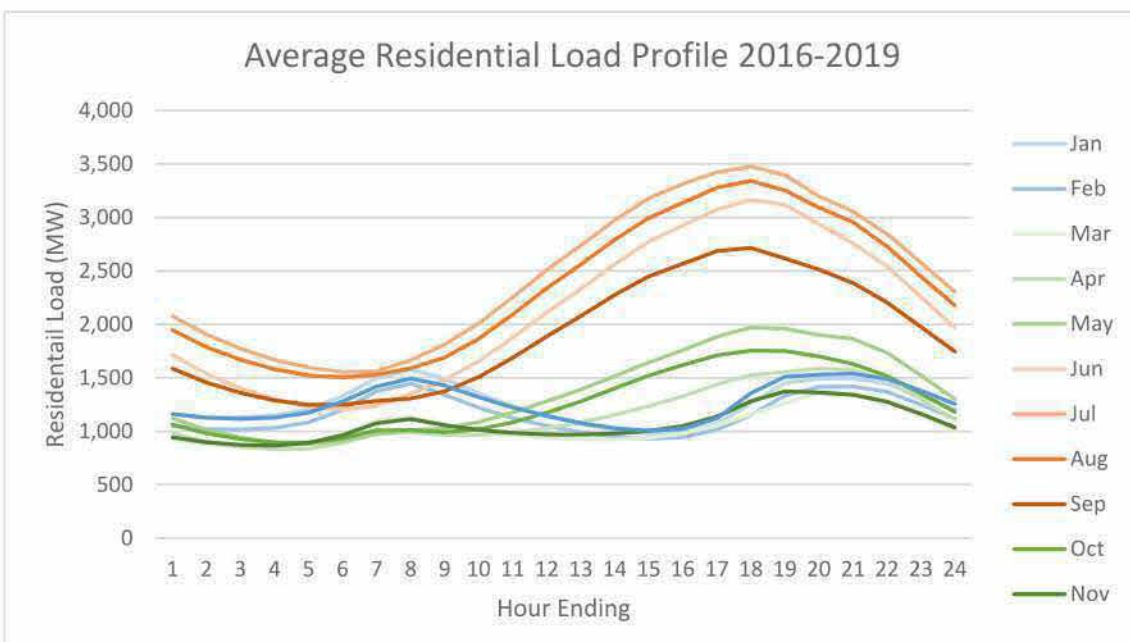

Figure 2 - Average Residential Class Load Profile 2016-2019

[13] Lucas Direct at 59, 61.

Additionally, none of the top 90 hours (the metric that APS use in analyzing system resource adequacy) in any of the recent years fell outside of the core summer months. In fact, the highest load hour from May or October was the 986th highest load hour in 2016, the 574th highest load hour in 2017, the 835th highest load hour in 2018, and 1,258th highest load hour in 2019. While Ms. Hobbick's contention that air-condition is occasionally needed during the shoulder months is correct, it is clear that system is not under stress in May and October.

Removing May and October from the summer season for residential rates would not make rates or bills more complex. Customers already switch between summer and winter months twice a year – that would not change under my proposal. Further, the Company has already proposed several changes to its rates, with the introduction of the super off-peak period for the R-2 and R-3 rate in its application and consolidating the six rates into three in its rebuttal. There is no reason that changing the months to more properly reflect cost drivers cannot also be incorporated into these changes.

Q26. MR. ALBERT CONTENDS THAT THE SYSTEM PEAK IS GETTING LATER. DID YOU ANALYZE THAT IN YOUR TESTIMONY?

A26. Yes, I did. Using data from the top 100 hours in 2016 to 2019, I calculated the "weighted average time" of both the system and residential class peaks and found that the system peak was actually trending earlier, while the residential class peak was stable.[14] Data from 2020 was not available while I was developing my testimony.

Mr. Albert appears to have conducted a new analysis for his rebuttal testimony suggesting that the peak day of 2020 had a net peak at 6:24 PM and a system peak at 5:39 PM.[15] He uses this data point to suggest the peak is getting later in the day, which supports maintaining the current TOU period of 3 PM to 8 PM.

[14] Lucas Direct at 63-64.
[15] Albert Rebuttal at 25. Mr. Albert indicated that the net peak at 6:24PM was "45 minutes later than the system peak load".

Q27. IS THE FACT THAT THE SINGLE HIGHEST LOAD HOUR OCCURRED AT 5:39 PM INDICATIVE THAT THE OVERALL LOAD SHAPE IS EVOLVING RAPIDLY?

A27. No, it is not. As Mr. Albert himself admits, the Company does not focus on the single peak hours, but rather evaluates the top 90 net load hours as "most of the Company's reliability needs are driving by the 90 highest net load hours in a given year"[16] Mr. Albert performed another update analysis that forecasted the hourly system loads in 2021. He noted that 84% of these hours fell between 3 PM to 8 PM.[17] However, 82% of these hours fall between 2 PM to 7 PM, a *de minimus* difference.

Q28. WHAT DO YOU RECOMMEND WITH REGARD TO THE TOU SEASONS AND PERIODS?

A28. I continue to recommend shortening the summer season to the four core months and moving the TOU peak hours to 2 PM to 7 PM, both of which are well supported by the Company's data and can be accomplished while simplifying the rates.

SEIA's R-TECH Modifications Should be Adopted

Q29. PLEASE DISCUSS THE CHANGES YOU RECOMMENDED TO THE R-TECH TARIFF.

A29. I proposed to migrate the R-TECH tariff from a complex, demand-based rate that included an off-peak (i.e. NCP) demand charge that required a customer to monitor their usage around the clock to a simpler volumetric TOU rate with a higher peak rate compared to the R-TOU-E tariff. I also recommended adding a rate differential between the peak and off-peak energy rates, noting that the current tariff had no differential half the year and a *de minimus* differential the other half.[18]

Q30. DID APS AGREE WITH YOUR RECOMMENDATIONS?

A30. No. Ms. Hobbick addressed this issue for the Company. She suggests that the extremely low adoption of the rate is due in part to the cost of battery storage being higher than expected when

[16] Albert Rebuttal at 23.
[17] Albert Rebuttal at 23.
[18] Lucas Direct at 71.

the pilot was approved.[19] She also argues that the off-peak demand charge "was implemented as a protection against the creation of a new peak during the evening hours" and that a volumetric-based rate "is simply not a rate designed with proper price signals for technology."[20] Ultimately, Ms. Hobbick recommends that the Company continue to offer the existing tariff and review its feasibility in a future proceeding.[21]

Q31. AS A FIRST MATTER, DOES THIS TARIFF REQUIRE A CUSTOMER HAVE ENERGY STORAGE TO PARTICIPATE?

A31. No. While energy storage is one of the qualifying technologies for this rate, it is not a requirement. A customer with an electric vehicle, a smart thermostat, and a variable speed pool pump could qualify for the tariff.[22] Similarly, a customer with solar and an electric vehicle could participate. As such, Ms. Hobbick's presumption that the cost of storage is slowing adoption of this rate cannot explain why other customers without storage but with other qualifying technology have not signed up for the rate.

Q32. DID YOU ANALYZE HOW MANY CUSTOMERS HAVE INTERCONNECTED SOLAR PLUS STORAGE SYSTEMS AND ELECTRIC VEHICLES ON THE COMPANY'S GRID?

A32. Yes. Based on the data from Arizona Goes Solar, I found that 694 customers had solar plus storage systems as of July 24, 2020, while a recent EPRI study suggests there are roughly 16,500 EVs in APS's territory.[23] Updated Arizona Goes Solar data shows that there are now 889 solar plus storage systems either operating or in the process of interconnecting on APS's grid.[24] While this figure is small compared to the total number of solar-only systems installed, there are clearly enough solar plus storage customers on the Company's system to show that the current R-TECH tariff is unattractive to solar plus storage customer and EV owners.

---

[19] Hobbick Rebuttal at 35.
[20] Hobbick Rebuttal at 35-36.
[21] Hobbick Rebuttal at 36.
[22] Lucas Direct at 66.
[23] Lucas Direct at 66-67.
[24] https://arizonagoessolar.org/aps/, accessed November 12, 2020.

Q33. DOES MS. HOBBICK'S SUPPORT OF THE OFF-PEAK DEMAND CHARGE ON THE R-TECH TARIFF DIRECTLY CONTRADICT HER TESTIMONY ON NCP DEMAND CHARGES ON THE R-2 AND R-3 TARIFFS?

A33. Yes. Ms. Hobbick, in rebutting Staff witness Dismukes, states that NCP demand charges such as the off-peak demand R-TECH charge "undermines conservation" and "is also overly punitive to customers because it requires them to manage their usage around the clock."[25] It is entirely inconsistent to argue against NCP charges in one tariff and support them in another. The fact that the R-TECH off-peak NCP rate is lower than the on-peak rate and provides the first 5 kW without cost does not overcome the fundamental flaws of NCP demand charges that Ms. Hobbick aptly identified.

Q34. MS. HOBBICK SUGGESTS THAT THE OFF-PEAK NCP CHARGE IS NEEDED TO PREVENT A NEW PEAK DURING EVENING HOURS. WHAT IS YOUR RESPONSE TO THIS?

A34. It is inconceivable that a tariff that is so poorly subscribed could somehow shift the entire residential class load or system load to a new evening peak. Even if the pilot was fully subscribed with 10,000 customers, it would represent fewer than 1% of the Company's customers. Further, the Company's other tariffs also have incentives to shift usage from peak hours to off-peak hours, including evening hours. Concern about this tariff triggering a new peak in the evenings is simply unwarranted.

Q35. DO YOU AGREE WITH MS. HOBBICK THAT RATES WITHOUT DEMAND CHARGES DO NOT SEND PROPER PRICE SIGNALS FOR TECHNOLOGY?

A35. No, I do not. As Ms. Hobbick herself admits, NCP demand charges such as the off-peak demand charge on the current R-TECH tariff do not sent proper price signals for any customer, regardless of their technology. Volumetric TOU rates, by contrast, send consistent and continual signals to reduce usage during peak hours throughout the month. Under the current R-TECH tariff, if a customer sets their monthly on-peak demand on the first day of the month,

---

[25] Hobbick Rebuttal at 31-32.

there is no incentive to reduce their demand below this level for the rest of the month, and almost no incentive to continue to shift their on-peak energy usage to off-peak periods given the tiny $0.01/kWh differential during the summer and $0.00/kWh differential during the winter.

By contrast, SEIA and AriSEIA's proposed volumetric TOU R-TECH alternative would provide a strong price signal to both reduce usage during on-peak hours and shift usage to off-peak and super off-peak hours through the entire month, regardless of when the peak demand level was set. Additionally, volumetric rates can be easily integrated into technology control systems for storage devices, electric vehicle chargers, and programmable thermostats. Contrary to Ms. Hobbick's suggestion, volumetric TOU rates are well suited to work with technology.

Q36. WHAT DO YOU RECOMMEND WITH REGARD TO THE R-TECH TARIFF?

A36. I recommend the Commission adopt the R-TECH modifications described in my direct testimony. The pilot rate has existed for more than three years and has only enrolled 55 customers.[26] Waiting longer before making changes, as suggested by Ms. Hobbick, is unnecessary as there is already ample evidence that customers have rejected the rate. Continuing with the current tariff in the face of obvious customer rejection will not meet the objectives of the pilot program to determine how more sophisticated rates can incent technology adoption.

The Grid Access Charge is Not Cost Based and Should be Eliminated

Q37. WHAT WAS YOUR RECOMMENDATION REGARDING THE GAC?

A37. I recommended that it be eliminated.[27] The GAC was a product of a settlement and is not cost based. The supposed rationale, erroneously repeated again by Ms. Hobbick, is that absent the GAC solar customers would continue to shift costs to non-solar customers: "Solar customers

---

[26] Hobbick Rebuttal at 35.
[27] Lucas Direct at 89.

on energy only rates pay significantly less than their cost of service compared to non-solar customers on energy-only rates."[28] However, I analyzed this exact issue and found that solar customers on the R-TOU-E rate have revenue equal to 83.9% of their CCOSS before the GAC was applied. This was a higher percentage than the R-XS and R-Basic subclasses, and very similar to the overall residential class.[29] It is true that the legacy solar rates did not perform as well on this metric, but those rates are closed to new customers.

Q38. MS. HOBBICK CLAIMS THAT SOLAR CUSTOMERS "REQUIRE ADDITIONAL USE OF THE DISTRIBUTION SYSTEM WHEN COMPARED TO NON-SOLAR CUSTOMERS," IMPLYING THAT THIS ADDITIONAL USE LEADS TO ADDITIONAL COSTS.[30] WAS APS ABLE TO DEMONSTRATE THIS?

A38. No, it was not. As discussed in more detail in the CCOSS section below, the Company was not able to demonstrate that residential solar customers required the installation or upgrade of equipment specifically to manage their exports or to provide "grid services" that were not already required to provide normal service.

Q39. MS. HOBBICK ALSO CLAIMS THE GAC WAS DESIGNED TO RECOVER A PORTION OF THE ADDITIONAL DISTRIBUTION LEVEL MONITORING AND VOLTAGE CONTROL FROM THE ADDITION OF RESIDENTIAL SOLAR CUSTOMERS. IS THIS CONSISTENT WITH APS'S PREVIOUS TESTIMONY?

A39. No, it is not. When asked about the origin of the GAC, APS's responded:

> The present grid access charge was developed and approved by the Arizona Corporation Commission as part of a settlement in the prior rate case, Docket No. E-01345A-16-0036, et. al. The approved amount was the result of negotiations and therefore not derived from any specific cost basis. The charge was instead set to provide a certain level of expected bill savings per kWh to solar customers.[31]

Further, the Company indicated that revenues and costs from the GAC "[are] not included in the proof-of revenue in this proceeding" and that "the associate costs are also removed from the cost-of-service-study."[32] Given the origin of the charge as a product of

---

[28] Hobbick Rebuttal at 37.
[29] Lucas Direct at 89.
[30] Hobbick Rebuttal at 38.
[31] Lucas Direct Attachment KL-29, SEIA 4.5a
[32] Lucas Direct Attachment KL-33, SEIA 5.6

settlement designed to target a certain level of bill savings and that the Company does not include its costs or revenues within the scope of the CCOSS, it is incorrect for Ms. Hobbick to retroactively claim the GAC is designed to recover costs associated with additional distribution level monitoring and voltage control as these items would absolutely be included in the CCOSS.

Q40. WHAT DO YOU RECOMMEND WITH REGARDS TO THE GAC?

A40. It should be eliminated. It is not cost based and the primary concern the Company raises regarding cost-shift does not apply to the R-TOU-E tariff, the only rate that actually has the GAC.

The Demand Limiter Should be Extended to Solar Customers

Q41. WHAT WAS YOUR RECOMMENDATION RELATED TO THE DEMAND LIMITER FOUND ON THE R-2 AND R-3 RATES?

A41. I recommended that the demand limiter, which reduces a customer's bill if they have an unusually high demand event in a month, be extended to solar customers. I supported this recommendation with an analysis of the frequency of demand-limited months from both solar and non-solar customers.[33]

Q42. DID APS AGREE WITH YOUR RECOMMENDATION?

A42. No. Ms. Hobbick claims that this recommendation "would disproportionately benefit solar customers and shift costs to non-solar customers" and that if extended to solar customers, the demand limiter would be triggered "nearly 12% of the time as opposed to 3% of the time for non-solar customers."

---

[33] Lucas Direct at 90.

Q43. DO THE COMPANY'S ACTUAL STATISTICS RELATED TO THE DEMAND LIMITER SUPPORT MS. HOBBICK'S CONTENTION THAT A CHANGE WOULD DISPROPORTIONATELY BENEFIT SOLAR CUSTOMERS?

A43. No, not at all. During the test year, non-solar customers that were offered demand-limiter protection saved $1.058 million on 88,000 bills.[34] This revenue shortfall is built into the rates, so solar customers and non-solar customers that do not benefit from the demand limiter face higher bills because of this policy. By contrast, had the Company offered the demand limiter to solar customers, they would have saved roughly $44,000 that would have had to be recovered through higher rates from both solar customers that did not benefit from the demand limiter and non-solar customers.[35] In other words, the non-solar customers that benefit from the demand limiter shift 24 times as many costs to solar customers than solar customers would hypothetically have shifted to non-solar customers.

Q44. DO YOU HAVE A RECOMMENDATION TO ADDRESS MS. HOBBICK'S CONCERN THAT SOLAR CUSTOMERS WOULD TRIGGER THE DEMAND LIMITER MORE OFTEN?

A44. Yes. I analyzed how often individual customers triggered the demand limiter. I found that among non-solar customers that triggered the demand limiter, about 75% only took advantage of it once or twice a year while roughly 7% triggered it five or more months per year. These figures were nearly identical for solar customers who would have triggered the demand limiter; 74% of solar customers would have triggered a hypothetical demand limiter only once or twice a year with 6.7% triggering it five or more times.

An appropriate response to this concern would be to simply limit the number of times the demand limiter can be used each year. Allowing two demand limited months per year would be reasonable as it would capture the majority of customers who experience inadvertent high demand events while preventing customers who habitually trigger the demand limiter from passing their costs to other customers. I recommend this be applied to all customers –

[34] Hobbick Rebuttal at 31.
[35] Lucas Direct at 94.

both solar and non-solar – as the demand limiter was originally intended address "very unlikely" high inadvertent demand levels.[36]

Q45. DID THE COMPANY HAVE ANY RESPONSE TO THIS RECOMMENDATION?

A45. Yes. In a discovery response, the Company stated that limiting the demand limiter could not be implemented "in any way that would be practical from a billing or customer service standpoint, especially for solar customers."[37]

Q46. WAS ANY ADDITIONAL DETAIL PROVIDED ON THIS POINT?

A46. No. No details were given why this proposal was impractical to implement, or why this would be "especially so" for solar customers.

Q47. WHAT DO YOU RECOMMEND ON THIS POINT?

A47. I recommend the Commission investigate why this reasonable proposal cannot be practically implemented in the Company's billing system. Cleary, logic to distinguish solar customers from non-solar customers is already implemented, so it is unclear why the program could not also track how often a customer has been granted a waiver from their demand. If the Company demonstrates to the Commission's satisfaction that placing a limit on how often the demand limiter is applied to each customer is indeed impractical, then the only equitable approach will be to allow unlimited access to the demand limiter for all customers, including all solar customers.

APS's Rebuttal on Maximum System Size is Without Merit

Q48. WHAT RECOMMENDATIONS DID YOU MAKE REGARDING THE MAXIMUM SYSTEM SIZE OF RESIDENTIAL AND NON-RESIDENTIAL SYSTEMS?

A48. I recommended that APS conform to Arizona regulations regarding net metering maximum size and connected load definitions and allow systems to be sized based on the AC rating of the inverter rather than the DC nameplate rating of the solar panels. For residential systems, this

[36] Lucas Direct at 92.
[37] Attachment KL-SR 1, SEIA 32.17.

would change the connection sizes to 15 kW_{AC}, 30 kW_{AC}, 45 kW_{AC}, and 60 kW_{AC} for 200-amp, 400-amp, 600-amp, and 800-amp service, respectively. For non-residential systems, I recommend adopting the Tucson Electric Power methodology of defining connected load as the maximum demand divided by 0.6, and after multiplying this value by 125%, applying it to the AC inverter rating.[38]

Q49. DID APS AGREE WITH YOUR RECOMMENDATION?

A49. No. APS witness Jacob Tetlow did not support these recommendations, stating that they could "impact reliability and increase costs for non-solar customers." He also opined that "because feeders have fixed capacity to add solar, this could also mean fewer customers per circuit are able to add systems."[39] In support of these points, Mr. Tetlow stated:

> However, using inverter settings as a replacement for nameplate capacity is inappropriate when qualifying for system interconnection rating because inverters can be sized larger or smaller than the solar system with which they are paired. Further, inverters have a typical life of approximately seven years compared with the longer life of a PV system, which are typically leased for 20 years. By using the size of an inverter to size the system, there is loss of transparency into the size of the PV system that can impact distribution system reliability if the true PV system impact is unknown, or costs to other customers if a customer exports more energy than initially approved.[40]

Q50. WHAT IS YOUR REACTION TO THIS PASSAGE?

A50. Mr. Tetlow's testimony that "inverters can be sized larger or smaller than the solar system," was unclear. When asked about this in discovery, he clarified that he was discussing the common practice of sizing the AC rating of the inverter slightly smaller than the DC rating of the panels.[41] For instance, residential systems commonly have an inverter load rating (ILR) of 1.2-1.25, meaning that for each kW_{AC} of inverter capacity, there is 1.2 to 1.25 kW_{DC} of panel capacity. This practice accounts for electrical losses in the system and maximizes the availability of inverter capacity.

[38] Lucas Direct at 103.
[39] Tetlow Rebuttal at 28.
[40] Tetlow Rebuttal at 29.
[41] Attachment KL-SR 2, SEIA 32.7.

There is a strong financial disincentive to dramatically oversize or undersize the inverter relative to the panels. If one were to attach a 20 kW_{AC} inverter to 10 kW_{DC} of panels, it would be a waste of inverter capacity as the panels could not produce enough power to hit its limit. Likewise, attaching 20 kW_{DC} of panels to a 10 kW_{AC} inverter would result in massive clipping of the panels' generation, since the inverter is not able to export more than 10 kW_{AC} at any given time, and would potential exceed the allowable DC current of the inverter as governed by UL listing.[42]

Aside from this financial incentive to stay within a narrow and predictable range of IRL, Mr. Tetlow's argument that the inverter rating is incorrect for interconnection ignores the flip side of his concern. If a homeowner were to pair a 20 kW_{AC} inverter to 10 kW_{DC} of panels, the inverter would never approach its maximum level and would use less capacity than its interconnection approval. But if a customer were to pair 20 kW_{DC} of panels to a 10 kW_{AC} inverter, the inverter would clip the output to 10 kW_{AC}, again using less capacity than its interconnection approval. In other words, the same argument Mr. Tetlow claims against using the AC capacity of the inverter can be applied to argue against using the DC capacity of the panels. Fortunately, the industry has long ago settled on a reasonable range of IRL for residential solar systems, making this issue moot.

Q51. WHAT ABOUT MR. TETLOW'S CONCERN THAT USING THE INVERTER RATING COULD RESULT IN A CUSTOMER "EXPORTING MORE ENERGY THAN INITIALLY APPROVED"?

A51. Given the rather unusual claim that a customer could somehow increase their system output beyond the initial approved limit, I requested clarification in a discovery request. Mr. Tetlow's response was telling:

> Both the installed DC solar panel size and the AC inverter capacity are important. For interconnection practice, APS believes A.A.C. R14-2-2601, et.seq. "Interconnection of Distributed Generation Facilities" appropriately defines system capacity and addresses circuit impact. The DC system can be significantly larger than the AC inverters. The AC inverter is likely the shorter lifetime component of this system and is likely to need

[42] The Underwriters Laboratory (UL) is a safety certification organization that tests products and determines safe operating parameters.

replacement before the DC system is affected. As changes are made in the future, this can lead to "masked" impacts where the same size DC system can appear to "produce" at a higher level if the AC inverters are modified… So, while the inverter does limit the amount exported to the grid, it is appropriate to size the total system based on the amount it could potentially produce. For example, as failed inverters are replaced over the 20+ year lifetime of the system a reasonable expectation of increased AC production, or larger AC inverters, could be realized, even if the DC size has not changed.[43]

Mr. Tetlow admits that only irrational behavior by customers will cause his concerns to be realized. First, for residential solar customers, there is no incentive to install DC panels that are "significantly larger" than the AC inverters. This would only add costs and cause clipped generation. As discussed above, ILRs in the 1.2-1.25 range are common and already account for system losses.

Second, because solar panels degrade slightly over time, it would not be a rational economic choice to replace an inverter with a larger inverter. When the inverter needs to be replaced, the DC output of the panels will be lower than when the system is new. Mr. Tetlow's scenario would require a customer to intentionally undersize their inverter when installing the new system, leading to years of clipped generation, and then increase the inverter size for what is now effectively a smaller DC system. This is not a rational action.

Third, the actions described by Mr. Tetlow are in direct violation of the Company's interconnection agreement. The agreement stipulates that the customer "shall not remove, alter, or otherwise modify or change the equipment specifications" after the final inspection. All changes must be submitted to APS, and "no change or modification may be made without the prior written acceptance of APS."[44] If APS is concerned about this issue, it has complete authority to deny inverter increases.

Finally, his admission that A.A.C. R-14-2-2601 "appropriately defines system capacity" proves the point. A.A.C R-14-2601 contains the definitions for distributed generation, and specifically declares the "maximum capacity" of a system is "the nameplate

[43] Attachment KL-SR 3, SEIA 32.9.
[44] APS Interconnection Requirements for Distributed Generation, 16.09. Available at https://www.aps.com/-/media/APS/APSCOM-PDFs/Residential/Service-Plans/Understanding-Solar/InterconnectReq.ashx?la=en

AC capacity of the Generating Facility"[45] The Rules are unambiguous; the maximum capacity of a PV system in the context of interconnection must be based on the AC rating of the system, which for a PV facility is the AC rating of the inverter.

Q52. WHAT IS MR. TETLOW'S BASIS FOR CLAIMING INVERTERS HAVE A SEVEN-YEAR LIFESPAN?

A52. There is no basis. Mr. Tetlow does not cite any document or studies to support this claim, and his response to a discovery request on this undermines his initial testimony. In his response, he states inverters have a "7 to 10 year lifespan", contradicting his testimony of a seven-year lifespan. He goes on to cite "industry data" that indicates inverters have a 10 to 15 year lifespan before claiming that Arizona's climate "tend[s]" to reduce lifespan from the industry average.[46] None of these statements are backed up by actual documentation.

One major manufacturer of inverters offer standard warranties of 12 years that are expandable to 20 to 25 years[47] Another solar provider offers a whole-system warranty of 25 years.[48] Regardless of Mr. Tetlow's unsupported claim, the differential between the lifespan of the panels and the inverter is completely irrelevant to the determination of the maximum system size. If an inverter does fail, the customer will have to replace it to restore the system to working order and will have the same motivations and obligation under the interconnection agreement to right-size the inverter as described above.

Q53. WHAT DO YOU RECOMMEND WITH THIS ISSUE?

A53. I recommend that the Commission require APS to conform its maximum system size calculations with Arizona Rules, including those recently promulgated on March 20, 2020 for distributed energy resources.[49] My direct testimony recommendations to use the AC rating of the inverter for residential systems and 125% of the maximum load divided by 0.6 for the AC

---

[45] A.A.C R-14-2601.
[46] Attachment KL-SR 4, SEIA 32.8.
[47] https://www.solaredge.com/sites/default/files/solaredge-warranty-may-2020.pdf, https://www.solaredge.com/us/warranty
[48] https://us.sunpower.com/home-solar-system-warranty
[49] Lucas Direct at 99.

rating of the inverter for commercial systems would be in compliance with the Rules and be consistent with the inverter's role of controlling system output.

APS CCOSS Rebuttal Presents No New Information and Should be Disregarded

Q54. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS WITH REGARD TO THE COMPANY'S CLASS COST OF SERVICE STUDY (CCOSS) METHODOLOGY AND MODEL.

A54. I made several critiques of APS's CCOSS methodology and model in my direct testimony. Chief among them was to replace APS's use of site energy and a "solar credit" with the conventional metric of delivered energy. I also recommend the Company increase the transparency of its methodology and model on issue such as data sources, load shapes, and customer growth, and to conform to the Commission's order on the use of class NCP. I also recommended the Commission investigate how to reduce metering costs associated with solar systems and to reconsider the requirement to install a production meter at every installation given advancements in modeling and inverter sophistication.[50]

Q55. WHAT WAS APS'S GENERAL RESPONSE TO YOUR CCOSS RECOMMENDATIONS?

A55. APS witness Leland Snook disagreed with my recommendations, claiming "All are invalid."[51]

Q56. DO YOU AGREE WITH THIS SWEEPING DECLARATION?

A56. No. Mr. Snook appears to have concluded that because SEIA and AriSEIA represent solar companies and customers, that any analysis I performed and all recommendations that I made were purely self-serving and thus could not have any merit ("Again, this proposal is self-serving for SEIA."[52] "SEIA's proposal is simply self-serving []."[53] "They are simply self-serving[]."[54] "The proposal … is only self-serving[.]"[55])

[50] Lucas Direct at 6.
[51] Snook Rebuttal at 37.
[52] Snook Rebuttal at 52.
[53] Snook Rebuttal at 53.
[54] Snook Rebuttal at 53.
[55] Snook Rebuttal at 54.

Mr. Snook's obvious and unwarranted hostility towards SEIA notwithstanding, his actual rebuttal on CCOSS points was mixed at best. He did not introduce any new concepts to the site vs. delivery load argument, quite literally repeating the same arguments (and reusing the same testimony) he has been making for years on the supposedly-existing-yet-never-quantified costs that DG solar customers create on the system. Mr. Snook's conflation of residential rooftop solar customers with commercial and industrial partial requirements customers misses the forest through the trees. He disavows the Commission's UNS Electric ("UNSE") order on the use of class NCP, claiming that APS's "much higher adoption of rooftop solar" somehow absolves it from what is a purely analytical issue. His claim that my transparency arguments stemmed from "a desire to manipulate the COSS model to incorporate this incorrect assumption", aside from being factually incorrect, neglects to acknowledge that increasing the model's transparency, accessibility, and flexibility would have been valuable in correcting several errors APS made in this case. Finally, he incorrectly asserts that I recommended a cost evaluation based on marginal costs.

Q57. PLEASE BRIEFLY SUMMARIZE THE SITE LOAD VS. DELIVERED LOAD ARGUMENT.

A57. APS's current CCOSS methodology begins by creating a "site load" value for solar customers. This is the load that a solar customer would have had absent their solar system. It is not the actual load that APS serves, as Mr. Snook admits.[56] The CCOSS then executes a convoluted process to undo this choice by creating a "solar credit" which the Company claims compensates the solar customers for their solar generation.

Q58. IS THIS A NEW ISSUE?

A58. No, although it has yet to be finally resolved by the Commission. The issue of site vs. delivered load has been discussed and debated for years since the "Value of Solar" ("VOS") docket[57] and the Company's previous rate case.[58] In fact, much of Mr. Snook's rebuttal

[56] Snook Rebuttal at 41.
[57] Docket No. E-00000J-14-0023.
[58] Docket No. E-01345A-16-0036.

testimony on this point[59] is word-for-word reproductions of his 2016 direct testimony in the previous rate case,[60] his 2016 direct testimony in the VOS docket,[61] and his responses to SEIA discovery requests.[62]

APS continues to claim that using delivered energy in the CCOSS would fail to include costs related to "grid services" but was unable to quantify any specific costs associated with these services beyond the conventional demand-related components needed to provide basic service from generating plants and the grid. APS also admitted that it had not added new feeders, capacitor banks or new voltage regulators and has not reconductored lines to accommodate residential PV customers.[63] Simply put, the mythical incremental costs associated with serving load beyond a solar customers' delivered load remain just that: a myth. Repetition does not make truth.

The Commission has yet to officially opine on the appropriateness of this issue. In the VOS docket, the Commission found that "record does not support approval of a specific COSS methodology in this proceeding" and directed utilities including APS to submit cost of service models which "shall be transparent[], accessible[], and flexible."[64] I recommend that the Commission put this issue to rest by determining that the appropriate and straight-forward method of including all costs associated with the actual load APS serves – the delivered load – be used as the basis for the CCOSS.

This decision would align the CCOSS with the same delivered load that is used for residential solar customers in the Company's resource adequacy process, its retail rate design, and the physical operation of its system.[65] If APS is ever able to quantify the costs of chimerical grid services such as "in-rush current" that are above and beyond the provision of

[59] Snook Rebuttal at 40-42.
[60] Docket No. E-01345A-16-0036, Snook Direct at 24-27. https://docket.images.azcc.gov/0000170848.pdf
[61] Docket No. E-00000J-14-0023, Snook Direct at 15-17, https://docket.images.azcc.gov/0000168552.pdf
[62] Lucas Direct, Attachment KL-6, SEIA 2.6b.
[63] Lucas Direct at 22.
[64] Decision 75859 at 174, Docket No. E-00000J-14-0023
[65] Lucas Direct at 27.

basic service to all customers, they can and should be included in the CCOSS based on delivered load.

Q59. MR. SNOOK STATES THAT "SEIA WITNESS LUCAS ALSO CLAIMS RESIDENTIAL ROOFTOP SOLAR CUSTOMERS ARE NO DIFFERENT THAN NON-SOLAR CUSTOMERS." IS THIS AN ACCURATE REPRESENTATION OF YOUR TESTIMONY?

A59. No, it is not. Mr. Snook did not cite the passage he is referring to, but I assume it is my discussion of the level of load diversity within the residential class.[66] My testimony actually states that there is no "normal" residential customers and that there exists substantial intra-class load diversity based on customer characteristics such as the presence or absence of electric heating, whether a customer is in a rural or urban area, or whether they live in an apartment or detached single family home. I pointed to an analysis performed using APS's own data that showed there are several groups of customers with distinct load shapes that are more numerous than solar customers.[67] Solar customers are but one of many identifiable customer groups with unique load shapes, and yet they are the only one singled out by APS for differential treatment in the CCOSS.

Q60. YOU MENTIONED THAT MR. SNOOK'S ASSERTION THAT RESIDENTIAL DG CUSTOMERS BE TREATED AS "PARTIAL REQUIREMENTS" CUSTOMERS THAT WARRANT SPECIAL RATE TREATMENT MISSES THE FOREST THROUGH THE TREES. PLEASE EXPLAIN.

A60. The concept of partial requirement customers originated well before there were rooftop solar systems. Larger commercial and industrial customers will sometimes have on-site generation, such as a CHP system that provides both electricity and space heat or hot water at a university or process heat at an industrial facility, but will also occasionally purchase power from the utility. These customers often take service under a "partial requirements" or "standby service" tariff whose rates reflect the difference in service from a utility's "full requirements" tariffs.

[66] Lucas Direct at 20-21.
[67] Lucas Direct at 21.

Partial requirements customers should contribute towards the cost of utility service, but since they do not rely on it 100% of the time, they appropriately pay less.

The major difference between C&I customers with large on-site generators and residential customers with rooftop solar is that C&I customers that have large on-site generators are much more likely to be one of only a few customers sharing distribution assets or to even have dedicated distribution assets that serve their load. Their load represents a substantial fraction of the load that the assets are designed to serve, and thus represent a substantial share of the cost as well.

By contrast, residential DG customers are physically interspersed throughout APS's grid. Residential assets such as substations and feeders serve hundreds if not thousands of customers, both solar and non-solar alike. If a single DG customer's load increases during an unplanned outage of their solar system, the aggregate load on the distribution assets serving that customer will barely change. Applying the same ratemaking principles to small residential solar systems as to multi-megawatt CHP systems is simply overkill.

Q61. WHAT IS MR. SNOOK'S JUSTIFICATION FOR IGNORING THE COMMISSION'S UNSE ORDER ON THE USE OF CLASS NCP FOR COST ALLOCATION?

A61. The Commission properly found that allocating distribution costs based on different residential subclass demands rather than on the peak demand of the entire residential class was inappropriate:

> Because the net combined residential NCP occurs in July, this is the basis for allocating the distribution circuit costs, and it is irrelevant that the DG customers' NCP occurs in April because the circuit must be built to serve the maximum total residential capacity which occurs in July. No additional cost is incurred to serve the DG customers' NCP.[68]

Mr. Snook attempts to sidestep the Commission's order by claiming that "APS has a much higher adoption rate of rooftop solar in the overall residential customer class than UNSE. The finding in the UNSE decision is specific to UNSE. APS's method is appropriate for APS, given its unique circumstances."[69] However, nothing in the Commission's order or reasoning

[68] Docket No. E-04204A-15-0142, Decision 76900 at 83.
[69] Snook Rebuttal at 38.

on this point is dependent on the adoption rate of rooftop solar Rather, the Commission properly identified the core issue with UNSE's approach that it is simply inappropriate from a cost of service perspective to allocate distribution circuit costs based on load that can already be accommodated. The Commission should reaffirm that its logic in the UNSE case applies to all utilities and direct APS to update its CCOSS on this point.

Q62. MR. SNOOK CLAIMS THAT YOUR RECOMMENDATIONS TO INCREASE THE TRANSPARENCY OF THE CCOSS WERE BORNE OUT OF A DESIRE TO "MANIPULATE THE COSS MODEL TO INCORPORATE THIS INCORRECT ASSUMPTION [RELATED TO DELIVERED LOAD]." HOW DO YOU RESPOND TO THIS?

A62. My recommendations to increase the transparency, accessibility, and flexibility of the CCOSS are a direct response to the Commission's order on this point.[70] This is the first rate case following the Commission's order where APS was required to provide CCOSS models that allow "all parties to be on equal footing with regard to the ability to use the cost of service model to illustrate their positions."[71] Far from "manipult[ing] the COSS model to incorporate this incorrect assumption," my desire to use the CCOSS to illustrate my position is entirely consistent with the Commission's order. The model's lack of transparency, flexibility, and accessibility made this task more difficult.

Further, APS original filing contained several inadvertent errors that were subsequently corrected during the discovery process. These included incorrect meter costs for solar customers and incorrect customer counts in the load research reports. Rather than provide an updated, functional version of the CCOSS with these mistakes corrected, APS provided a hardcopy extract of some of the CCOSS values.[72] These errors, along with the previously mentioned class NCP adjustment, were more difficult to correct in the CCOSS than was necessary or appropriate.

---

[70] Docket NO. E-00000J-14-0023, Decision 75859 at 144.
[71] Docket NO. E-00000J-14-0023, Decision 75859 at 144.
[72] Lucas Direct at 42.

Q63. MR. SNOOK ASSERTS THAT "SEIA WITNESS LUCAS ALSO CLAIMS THAT THIS COST EVALUATION SHOULD BE BASED ON MARGINAL COSTS." DO YOU MAKE THIS CLAIM?

A63. No. Mr. Snook did not provide many references in his rebuttal testimony, and consequently I am unable to determine what passage of my testimony he was referring to. This statement is immediately preceded by the discussion of partial requirements customers. While I do discuss marginal costs in my commercial rate design testimony (one area in which Mr. Snook agrees they may be appropriate to consider), I did not discuss marginal costs in the context of the CCOSS.

Q64. MR. SNOOK DESCRIBES THE REGULATORY ASSISTANCE PROJECT AS AN "ADVOCACY GROUP FOR ENERGY EFFICIENCY AND DISTRIBUTED SOLAR RESOURCES" AND THE RAP MANUAL ON COST ALLOCATION "AN ADVOCACY WHITE PAPER." DO YOU AGREE WITH THIS CHARACTERIZATION?

A64. I do not. RAP is a well-respected organization that works on regulatory issues throughout the world. Its staff includes several former commissioners, environmental regulators, state consumer advocates, industry executives, and system operators. Its board of directors includes more former commissioners, academics, and industry experts.[73] The Manual on Cost Allocation was reviewed by many former commissioners as well.

Mr. Snook's suggestion that this group is merely an advocacy group for energy efficiency and distributed solar resources simply because its mission "is dedicated to accelerating the transition to a clean, reliable, and efficiency energy future" is misplaced. By this standard, the Arizona Corporation Commission must also be painted with the same brush considering its landmark, bipartisan decision to enact a 100% carbon reduction for utilities through the increase of renewable and clean energy, energy efficiency, and distributed resources.[74] I strongly recommend the Commission consider the recommendations in the RAP Manual on Cost Allocation as it embarks on the journey to decarbonize Arizona's utilities.

---

[73] https://www.raponline.org/about/#staff
[74] https://www.greentechmedia.com/articles/read/arizonas-100-clean-energy-rules-heads-to-the-people

The Commission Should Consider SEIA and AriSEIA's Commercial Rate Design Recommendations

Q65. WHAT WERE YOUR RECOMMENDATIONS RELATED TO COMMERCIAL RATE DESIGN?

A65. I recommended several changes aimed to reduce the disincentive to reducing energy and demand usage on the E-32 grouping of rates. These included eliminating the declining block structure, removing the demand ratchet from the E-32 L tariff, better aligning the "edges" between tariffs, and making several changes to the E-32 L Storage Pilot tariff.[75]

Q66. DID APS AGREE WITH YOUR RECOMMENDATIONS?

A66. No, it did not. Mr. Snook again dismissed my recommendations out of hand, claiming "they unjustifiably favor customers that adopt SEIA's favored technologies and shift costs to other customers by raising their rates and bills." Mr. Snook continued that "APS believes that rates should be technology agnostic."[76]

Q67. ARE THE RATE DESIGN CHANGES THAT YOU RECOMMEND "TECHNOLOGY AGNOSTIC"?

A67. Yes. With the exception of the E-32 L Storage Pilot program, which is intended to create a storage-friendly rate, I did not make any recommendations that would be limited to a particular technology. The elimination of the declining block structure and removal of the demand ratchet has the potential to benefit customers who wish to reduce load through any means, including installing energy efficiency measures, participating in demand response programs, installing a building load control system, installing distributed generation, or installing storage. This is about as technology agnostic as one can be. Given the critical role that demand-side management will have in attaining Arizona's decarbonization goals, dismissing rate design changes that encourage energy and demand reductions out of hand is unwise.

[75] Lucas Direct at 131.
[76] Snook Rebuttal at 47-48.

Q68. WHAT WERE THE REASONS THAT MR. SNOOK OPPOSES YOUR RECOMMENDED CHANGES ON THE E-32 S AND E-32 M RATES?

A68. I recommended changing from what Mr. Snook calls a "unique design" that utilizes a "load factor" rate structure to a more traditional demand and energy rate.[77] Mr. Snook indicates that APS is not "conceptually" opposed to changing the rate design, but "APS does not support this rate change at this time because SEIA witness Lucas has not provided any compelling reasons for making this change, no customer groups are proposing this change, and the change would create disparate bill impacts for customers, which have not been investigated."[78]

Q69. DID YOU PROVIDE ANY "COMPELLING REASONS" FOR MAKING THESE CHANGES?

A69. Yes. I analyzed the impact of customers whose demand levels placed them close to the edge of the various E-32 tariffs. I found that a very small change in demand (e.g. from 399 kW to 401 kW or from 101 kW to 99 kW) that would have no material impact on the cost to serve customers could have a severe impact on the individual customer's bill. Further, this edge effect was most prevalent when switching between tariff types (i.e. between the traditional E-32 XS/XSD and the "unique" E-32 S and between the "unique" E-32 M and traditional E-32 L) than when switching between like tariffs (i.e. between the E-32 S and E-32 M and the E-32 L and E-34).[79]

In one example, I calculated that a customer who reduced their peak demand from 401 kW to 399 kW could see an annual increase of $12,000 or 5.4% on their non-BSC bill if they were moved from the E-32 L tariff to the E-32 M tariff. There is no rate making policy justification for imposing this magnitude of rate shock on an individual customer due to such a small change in their billing demand. Mr. Snooks concern about "disparate bill impacts for customers" is not just a hypothetical issue with my proposed changes, it is happening right now under APS's current rate structure!

---

[77] Lucas Direct at 105.
[78] Snook Rebuttal at 51.
[79] Lucas Direct at 107.

Q70. IS MR. SNOOK'S CRITIQUE THAT NO OTHER CUSTOMER GROUP PROPOSED CHANGES TO THE E-32 COMMERCIAL TARIFFS RELEVANT?[80]

A70. No. While it is not unusual for very large individual customers such as Walmart, Freeport Minerals, and the Federal Executive Agencies to directly intervene in cases such as this, these companies skew towards the larger commercial rates such as E-32 L and E-34. There is no state-sponsored consumer advocate for small- and medium-sized commercial customers, as there is for residential customers through RUCO. Intervening and actively participating in a rate case requires substantial resources, with costs easily escalating into the tens of thousands of dollars. The absence of these intervenors does not mean that every commercial customer who does not have the resources of a Walmart is completely satisfied with their current rate structure.

Q71. IS MR. SNOOK'S CRITIQUE THAT THE CHANGES WOULD CREATE DISPARATE BILL IMPACTS FOR CUSTOMERS A REASON NOT TO PURSUE THIS CHANGE?[81]

A71. No. Mr. Snook is correct that a more thorough analysis could be performed to identify the types and magnitudes of rate impacts that would result from this change. But given that very real disparate bill impacts are already happening because of the "unique" rate design for E-32 S and E-32 M customers, I recommend the Commission direct APS to quickly analyze this issue and propose a new rate structure for these classes that minimizes these disruptions.

Q72. MR. SNOOK DID NOT AGREE WITH YOUR RECOMMENDATION TO ELIMINATE THE DEMAND RATCHET ON THE E-32 L TARIFF. WHAT WERE HIS REASONS?

A72. Once again, Mr. Snook dismissed the proposed change as "self-serving for SEIA" without challenging the actual substance of my analysis.[82] Mr. Snook claims that demand ratchets are "a cost-based rate component that helps to match the demand component of each customer's bill with their actual cost of service."[83] However, he provides no support for this claim, and

[80] Snook Rebuttal at 51.
[81] Snook Rebuttal at 51.
[82] Snook Rebuttal at 52.
[83] Snook Rebuttal at 52.

does not refute my analysis showing that only a fraction of the Company's non-customer distribution costs are allocated based the individual max allocator, with the vast majority allocated based on the Class NCP allocator.[84] He also does not refute the inappropriateness of applying the demand ratchet to the transmission and generation demand charges despite the clear fact that power supply assets are designed to serve the coincident peak load of the entire system, not the individual load of a single customer.

The demand ratchet can be a substantial obstacle for customer trying to manage their demand through whatever means they choose. A single bad 15-minute period anytime between May and October can set the demand ratchet, even if the time of this demand spike in no way incurs incremental load on the system and thus incremental cost to the system. This is an overly punitive result which, despite Mr. Snook's protestations, is not cost-based. I reiterate my recommendation that the Commission eliminate the demand ratchet, or barring that, to reduce it to a lower level such as 50% and apply it only to the distribution demand portion of the bill.

Q73. WHAT CHANGES DID YOU RECOMMEND TO THE E-32 STORAGE PILOT (E-32 SP) RATE?

A73. Given the complete lack of customer participation on this rate, I proposed a number of changes to the E-32 SP rate that would allow customers to be able to make a rational choice to select the pilot rate. These included relaxing the minimum bill reduction level, reducing the on-peak period to four hours, creating a reasonable rate differential between the on-peak and remaining hour demand rate, increasing the differential between energy rates, and allowing sufficient time for storage systems to be fully charged by paired solar.[85]

Q74. HOW DID MR. SNOOK RESPOND TO YOUR PROPOSAL?

A74. Mr. Snook's response was consistent with the rest of his rebuttal testimony, dismissing some of the changes as "only self-serving to promote distributed solar."[86] He begrudgingly "agrees to further investigate the storage rate issue," but only after falsely claiming that SEIA's is now

[84] Lucas Direct at 113.
[85] Lucas Direct at 131.
[86] Snook Rebuttal at 54.

seeking changes because "the solar parties' previous rate design was ineffective at driving the adoption of storage technology."[87]

Q75. WHAT IS THE TRUE ORIGIN OF THE E-32 SP RATE?

A75. By the Company's own admission, the E-32 SP rate was based on a similar rate from TEP.[88] In the case, solar parties did push for a non-ratcheted option to TEP's large commercial customer rate for storage customers, but Mr. Snook's suggestion that the rate was designed by solar parties is incorrect.

The Commission approved the concept on a non-ratcheted commercial rate for storage customers but did not provide detailed directions to TEP.[89] TEP – not the solar parties – developed the rate, which was subsequently submitted to and approved by the Commission.[90] APS's tariff shares many of the same characteristics of the TEP storage rate, including the use of "remaining hours," an extremely long effective peak period, and a small differential between on-peak and off-peak energy rates.[91] It also shares the key characteristic of having zero customers.[92]

Q76. REGARDLESS OF WHERE THE RATE DESIGN CAME FROM, IS IT ACCOMPLISHING THE COMMISSION'S GOALS TO CREATE A "STORAGE-FRIENDLY RATE"?

A76. Not at all. When the Commission found "that it would be useful to create a new, optional, non-ratcheted, storage-friendly rate," it could not have conceived that this goal would be met through tariffs at both APS and TEP that did not enlist a single subscriber.[93] The E-32 SP tariff is broken, plain and simple; there is no need to "further investigate the storage rate issue" as Mr. Snook suggests. SEIA's recommendations to improve the tariff may entice customers to sign up and to finally provide the valuable data that the Commission requested.

---

[87] Snook Rebuttal at 54.
[88] Lucas Direct at 121.
[89] Decision 75975 at 188, Docket E-01933A-15-0322
[90] TEP Notice of Compliance, March 15, 2017. Docket No. E-01345A-16-0036. Available at https://docket.images.azcc.gov/0000178056.pdf.
[91] TEP Larger General Service Time-of-use Storage Program rate, available at https://www.tep.com/wp-content/uploads/2018/02/223-TGLGSTB.pdf
[92] Lucas Direct at 128.
[93] Decision 76295 at 78, Docket No. E-01345A-16-0036.

Q77. DO YOU RECOMMEND THAT A CUSTOMER NEED NOT INSTALL STORAGE TO BE ON THE STORAGE PILOT RATE?

A77. No. Mr. Snook misconstrued my recommendation to eliminate the 20% minimum reduction threshold, which for many customers would be physically impossible to meet through a paired solar and storage system. Rather, I noted that the "Company should be ambivalent whether it attains the same demand reduction from more customers" through a lower minimum demand reduction rather through fewer customers with a higher minimum demand reduction.[94]

Q78. WHY IS THE 20% PEAK DEMAND REDUCTION THRESHOLD MORE DIFFICULT TO ATTAIN THAN IT APPEARS?

A78. Because it ignores the minimum demand level that a customer has. Suppose an E-32 L customer has a peak demand of 1,000 kW and minimum demand of 400 kW. The controllable demand with energy storage is not 1,000 kW, but rather 600 kW difference between peak and the minimum demand. The E-32 SP peak reduction requirement would be 200 kW, which is actually 33% of the controllable demand. Attaining this level of demand reduction represents a much more difficult task.

The higher the demand reduction requirement, the more kWh of storage must be added to ensure that demand can be managed as long as needed. The non-linear relationship between required demand reduction and energy duration required to meet the demand reduction can quickly make systems uneconomical. For this reason, a lower demand reduction threshold of 5% to 10% would be more aligned with the customer's controllable loads and enable greater participation.

IV. CONCLUSION

Q79. WHAT CONCLUSIONS HAVE YOU REACHED THROUGH YOUR SURREBUTTAL TESTIMONY?

A79. I find that Staff witness Dr. Dismukes's recommendation to change to an NCP demand measurement highly problematic. While he contends that APS customers have sufficient

---

[94] Lucas Direct at 130.

experience on three-part rates to manage an NCP demand charge, he overlooks the fundamental defects in this approach. NCP demand charges do not reflect cost-causation, are overly punitive, and undermine conservation. I also find that his recommendation to drop the seasonality of demand rates and TOU energy rates on the R-2 and R-3 tariff lacks support. Demand charges for generation and transmission are appropriately higher in the summer months than the winter months, as are energy generation rates during peak hours compared to off-peak hours. This sends a valuable price signal that can reduce demand during periods of high load and reduce costs for all customers. Finally, I disagree that the super off-peak period should be removed from the R-TOU-E rate, and instead recommend it be added to the R-2 and R-3 tariff. The super off-peak period corresponds with periods of low demand and low costs. These are the exact hours that efficient consumption should be encouraged, through activities such as precooling a house or charging an electric vehicle. These rate design recommendations from Dr. Dismukes should be rejected.

I find the bulk of APS's rebuttal testimony unconvincing. While there are real and meaningful policy differences between SEIA's positions and APS's positions, few of the Company's witnesses challenged my technical analyses on matters related to cost of service and rate design. The rebuttal that was offered either sought to wave away the underlying analyses in the name of "rate simplicity," repeat stale testimony from years ago, or dismiss all SEIA proposals as merely "self-serving."

APS's residential TOU peak periods should be changed from 3 PM to 8 PM weekdays May through October to 2 PM to 7 PM weekdays June through September. These are the hours most directly supported through multiply analyses. While I appreciate the Company's concern about simplifying rates, it is already proposing substantial changes to its rate structure. Adjusting the TOU peak periods can and should be included in these changes.

The R-TECH rate is not working. APS's contention that unexpectedly high battery costs are holding back adoption is not supported. There are nearly a thousand solar plus storage installations and more than 16,000 electric vehicles in the Company's territory, with only a few dozen customers signed up to the rate. SEIA's recommendations should be adopted in this case to motivate customers to engage with this rate, control their demand, and reduce costs for all customers. Further delay is not warranted.

The GAC is not cost based, and, by the Company's own admission, it never was. It was the product of a settlement that was attempting to address an issue caused by legacy rates that are now closed. The GAC should be eliminated as solar customers on the R-TOU-E tariff contribute more towards their CCOSS than several other residential rate subclasses and nearly as much as the overall residential class.

The Company's demand limiter should be extended to solar customers. The Company's concerns about how often the demand limiter will be triggered can be easily addressed for all customers by limiting the number of times per year it can be used to two. This change will protect more non-solar customers than solar customers, as there is more than 24 times as many costs associated with non-solar customer demand limitations than a hypothetical solar customer demand limiter.

APS should conform its maximum system size recommendation to Arizona Rules by calculating limits based on the kW_{AC} rating of the inverter. APS's concerns about a lack of transparency through this method are unfounded based on the operating relationship between the DC rating of the panels and the AC rating of the inverter.

The Commission should direct APS to use the delivered load of solar customers in its CCOSS. The Company's convoluted site load / solar credit that purports to capture incremental costs to serve DG customers approach lacks merit. The fact is that APS was not able to quantify any specific costs related to these "grid services" for DG customers, despite having been asked multiple times. Absent specific cost data on used and useful assets needed to serve these customers beyond what is already required to meet their delivered load, the Company must use the logically consistent approach that is does in resource adequacy, forecasting, rate design, and operation and use delivered load in its CCOSS methodology and model.

The Commission should adopt SEIA's commercial rate design recommendations. The demand ratchet and declining block rate components hamper demand side management efforts. The E-32 S and E-32 M's unique rate design unjustly causes major rate shocks to customers that switch to other tariffs because of small changes to their demand. The E-32 SP is not meeting its purpose of being a "storage friendly" tariff and needs major changes to open up the nascent commercial storage market in APS's territory.

Q80. DOES THIS CONCLUDE YOUR TESTIMONY?

A80. Yes, it does.

Attachment KL-SR 1, SEIA 32.17.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
THIRTY SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
NOVEMBER 10, 2020

SEIA 32.17: Please refer to the Rebuttal Testimony of Jessica E. Hobbick at 38, which states "Lastly, if the demand limiter described earlier in this testimony were offered to solar customers, it would trigger four times as often, nearly 12% of the time as opposed to 3% of the time for nonsolar customers."

a) Please provide the analyses that support the frequency that the demand limiter would be triggered by solar and non-solar customers in their original format with formulas intact.

b) Does the Company put any limits on how often the demand limiter can be triggered by an individual non-solar customer?

c) Could the Company place limits on how often the demand limiter can be triggered by an individual customer?

d) If the Company's concern is that solar customers will trigger the demand limiter more often, why does it not propose to limit the number of times that a solar customers can utilize the demand limiter rather than prevent the entire solar customer base from utilizing the demand limiter?

e) Confirm that the $1.058 million in customer savings from the demand limiter are eventually recovered from customers who did not benefit from the demand limiter. If deny, please explain.

Response: a) Please see attachment ExcelAPS19RC02123 for the requested information.

b) No.

c) Not in any way that would be practical from a billing or customer service standpoint, especially for solar customers.

d) The demand limiter would not be appropriate for solar customers from a cost-of-service standpoint, even if capped, as discussed in the Company's responses to SEIA 7.10 and 24.1. In addition, it would not be practical from a billing and customer service standpoint, as discussed in the response to part c.

e) Unrecovered demand-related costs that occur due to the demand limiter feature would be recovered in a subsequent rate case from both the demand-limited customers and the

Response to SEIA 32.17 (continued):	other customers in the demand-rate class. However, the other non-solar customers in the demand-rate class would also benefit from the feature, even if their monthly demands were not high enough to activate it, because the demand limiter helps protect from unusual and unanticipated demand fluctuations relative to usage.

Attachment KL-SR 2, SEIA 32.7.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
THIRTY SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
NOVEMBER 10, 2020

SEIA 32.7: Please refer to the Rebuttal Testimony of Jacob Tetlow at 29, which states "However, using inverter settings as a replacement for nameplate capacity is inappropriate when qualifying for system interconnection rating because inverters can be sized larger or smaller than the solar system with which they are paired."

a) Please explain what is meant by "inverters can be sized larger or smaller than the solar system with which they are paired."

b) Please explain Mr. Tetlow's understanding of the typical relationship of the size between the DC nameplate rating and AC inverter rating of a solar system.

c) Please explain Mr. Tetlow's understanding of whether a PV system outputs power to the host customer based on the DC nameplate capacity of the system or based on the AC inverter rating of the system.

d) Is it Mr. Tetlow's understanding that the AC inverter output power of a PV system can be increased past its maximum level by increasing the number of panels connected to the PV system?

e) Does the Company base its interconnection of utility-scale solar generators on the DC nameplate of the system or the AC inverter rating of the system?

Response: a) It is APS's understanding that the DC/AC ratio of a PV installation is routinely greater than one, meaning that the DC system size is larger than the AC inverter rating.

b) The DC represents the capacity of the PV to produce electricity in kW. The AC represents the capacity of the inverter to inject AC electricity into the home or grid. If the solar irradiance and production in DC exceed the AC value, the excess is clipped.

c) Please see the Company's response to part b.

d) No.

e) Both AC and DC information must be taken into account. Requirements for utility scale and small residential and commercial installations are not comparable. Utility scale

Response to SEIA 32.7 (continued):	requirements are governed by WECC and NERC, including data collection and modeling requirements of utility scale sites that are typically not available at the residential and commercial level. Vendors are required to provide these validated and documented models to utilities. Additionally, there are steady-state production considerations. There are also transient and dynamic, and short-circuit considerations, as well the data required for WECC and NERC models and analysis, used to study and assess fault response for bulk-electric-system representation.

Attachment KL-SR 3, SEIA 32.9.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
THIRTY SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
NOVEMBER 10, 2020

SEIA 32.9: Please refer to the Rebuttal Testimony of Jacob Tetlow at 29, which states "By using the size of an inverter to size the system, there is loss of transparency into the size of the PV system that can impact distribution system reliability if the true PV system impact is unknown, or costs to other customers if a customer exports more energy than initially approved."

a) Please explain how the "size of the PV system" is somehow masked by using the size of the inverter, which is the component that dictates how much power a PV system can provide to the customer or the grid?

b) Please explain how under Mr. Lucas's proposal a customer would be able to export more energy than initially approved.

Response:

a) The context of the testimony refers to the sizing practices of PV systems. Both the installed DC solar panel size and the AC inverter capacity are important. For interconnection practice, APS believes A.A.C. R14-2-2601, *et.seq.* "Interconnection of Distributed Generation Facilities" appropriately defines system capacity and addresses circuit impact. The DC system can be significantly larger than the AC inverters. The AC inverter is likely the shorter lifetime component of this system and is likely to need replacement before the DC system is affected. As changes are made in the future, this can lead to "masked" impacts where the same size DC system can appear to "produce" at a higher level if the AC inverters are modified.

b) The size of the DC system ultimately dictates how much power can be produced. So, while the inverter does limit the amount exported to the grid, it is appropriate to size the total system based on the amount it could potentially produce. For example, as failed inverters are replaced over the 20+ year lifetime of the system a reasonable expectation of increased AC production, or larger AC inverters, could be realized, even if the DC size has not changed. Interconnection agreements generally require customers to contact the utility if changes are being made, but no proactive enforceable requirement exists.

Witness: Jacob Tetlow

Attachment KL-SR 4, SEIA 32.8.

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
THIRTY SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
NOVEMBER 10, 2020

SEIA 32.8: Please refer to the Rebuttal Testimony of Jacob Tetlow at 29, which states. "Further, inverters have a typical life of approximately seven years compared with the longer life of a PV system, which are typically leased for 20 years." Please provide all analyses and documentation that supports these claims.

Response: The 7- to 10-year life expectation is based on APS's decades of experience operating both residential and utility scale PV sites, and on industry data. For example PV Panel & Inverter Life Expectancy indicates the average inverter lasts 10 to 15 years as an industry average. However, Arizona's extreme summer temperatures tend to reduce the expected lifetime from industry averages. This is similar to other electronic technologies like car batteries and outdoor electronics.

Witness: Jacob Tetlow